nationalgrid

United States Operations

Transmission Group Procedure

TGP28

Transmission Planning Guide

Authorized by

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1.0 Change Control

Version	Date	Modification	Author(s)	Reviews and Approvals by
Issue 1	06 August 2007	Initial Document	Philip J. Tatro	David Wright
Issue 2	29 February 2007	Removed “Confidential” from page header	Philip J. Tatro	David Wright
Issue 3	22 November 2010	Added sections 3.5 (System models), 5.4 (Substation design considerations); provided additional guidance on several other topics interspersed in the document. Added referenced to BPS analysis in section 3.9. Added section 4.5 on generator low voltage ride through. Revised study horizon from up to 10 years to up to 15 years. Added items to section 2.3 on Operational considerations	Philip J. Tatro, Dana Walters	Paul Renaud

This document should be reviewed at least every two years.

2.0 Introduction

2.1 Objective of the Transmission Planning Guide

The objective of the Transmission Planning Guide is to define the criteria and standards used to assess the reliability of the existing and future National Grid transmission system for reasonably anticipated operating conditions and to provide guidance, with consideration of public safety and safety of operations and personnel, in the design of future modifications or upgrades to the transmission system. The guide is a design tool and is not intended to address unusual or unanticipated operating conditions.

2.2 Planning and Design Criteria

All National Grid facilities that are part of the bulk power system and part of the interconnected National Grid system shall be designed in accordance with the latest versions of the NERC Reliability Standards, Northeast Power Coordinating Council (NPCC) Criteria, ISO-New England Reliability Standards, New York State Reliability Council (NYSRC) Reliability Rules, and the National Grid Design Criteria. The fundamental guiding documents are:

- NERC Reliability Standards TPL-001, *System Performance Under Normal Conditions*, TPL-002, *System Performance Following Loss of a Single BES Element*, TPL-003, *System Performance Following Loss of Two or More BES Elements*, and TPL-004, *System Performance Following Extreme BES Events*,
- NPCC Directory #1, *Design and Operation of the Bulk Power System* and Directory #4, *Bulk Power System Protection Criteria*,
- *Reliability Standards for the New England Area Bulk Power Supply System* (ISO-NE Planning Procedure No. 3),
- *New York State Reliability Council Reliability Rules for Planning and Operation of the New York State Power System*, and
- National Grid Transmission Planning Guide (this document).

Interconnections of new generators to the National Grid transmission system in New England shall be configured and designed in compliance with the ISO-New England document, “General Transmission System Design Requirements for the Interconnection of New Generators (Resources) to the Administered Transmission System.” If corresponding New York ISO requirements are established, interconnections to the National Grid transmission system in New York will be configured and designed in compliance with those requirements.

All National Grid facilities operated at 115 kV and above in New York and 69 kV and above in New England shall be designed in accordance with the latest version of this document.

All National Grid or National Grid transmission customers' facilities which are served by transmission providers other than National Grid shall be designed in accordance with the planning and design criteria of the transmission supplier and the applicable NERC, NPCC, ISO-NE, and NYSRC documents.

Detailed design of facilities may require additional guidance from industry or other technical standards which are not addressed by any of the documents referenced in this guide.

2.3 Operational Considerations in Planning and Design

The system should be planned and designed with consideration for ease of operation and with input from Operations. Such considerations include, but are not limited to:

- utilization of standard components to facilitate availability of spare parts
- optimization of post contingency switching operations
- use and location of switching devices (ex. Adding sectionalizing switches on either side of a substation tap to reduce Load at Risk (LAR) for scheduled outages)
- switch capabilities (need to consult with Operations to confirm that any proposed switches meet operating criteria)
- reduction of operational risks
- judicious use of Special Protection Systems (SPSs)
- impact on the underlying distribution system (e.g. thermal, short circuit, automated switching schemes)
- use of SCADA, telemetry, etc to communicate the Control Center Energy Management System (EMS)
- impact to system restoration plan
- need, use, and location of reactive supplies
- development of operating procedures for new or revised facilities
- longevity of the solution to minimize rework
- operational and outage issues associated with construction
- integration of multiple needs to provide an efficient approach to performing upgrades or replacements

3.0 System Studies

3.1 Basic Types of Studies

The basic types of studies conducted to assess conformance with the criteria and standards stated in this guide include but are not limited to Powerflow, Stability, Short Circuit, and Protection Coordination.

3.2 Study Horizon

The lead time required to plan, permit, license, and construct transmission system upgrades is typically between one and ten years depending on the complexity of the project. Some very large and complex projects, which are less common, may even require lead times of up to 15 years. As a result, investments in the transmission system should be evaluated for different planning horizons in the one to fifteen-year range. The typical horizons are referred to as near term (one to three years), mid-term (three to six years), and long term (six or more years). Projects taking less than a year to implement tend to consist of non-construction alternatives that are addressed by operating studies.

3.3 Future Facilities

Planned facilities should not automatically be assumed to be in-service during study periods after the planned in-service date. Sensitivity analysis should be performed to identify interdependencies of the planned facilities. These interdependencies should be clearly identified in the results and recommendations.

3.4 Equipment Thermal Ratings

Thermal ratings of each load carrying element in the system are determined such that maximum use can be made of the equipment without damage or undue loss of equipment life. The thermal ratings of each transmission circuit reflect the most limiting series elements within the circuit. The existing rating procedures are based on guidance provided by the NEPOOL System Design Task Force (SDTF) in Planning Policy 7 (PP 7 Procedures for Determining and Implementing Transmission Facility Ratings in New England), the NYPP Task Force Report on Tie Line Ratings (1995), and industry standards. Similar rating procedures have been developed for rating National Grid facilities in New England and New York. The applicable National Grid procedure will be applied to all new and modified facilities. The principal variables used to derive the ratings include specific equipment design, season, ambient conditions, maximum allowable equipment operating temperatures as a function of time, and physical parameters of the equipment. Procedures for calculating the thermal ratings are subject to change.

Equipment ratings are summarized in the following table by durations of allowable loadings for three types of facilities. Where applicable, actions that must be taken to relieve equipment loadings within the specified time period also are included.

Equipment	RATINGS			
	Normal	Long Time Emergency (LTE)	Short Time Emergency (STE)	Drastic Action Limit (DAL)[4]
Overhead Transmission	Continuous	Loading must be reduced below the Normal rating within 4 hours[2]	Loading must be reduced below the LTE rating within 15 minutes	requires immediate action to reduce loading below the LTE rating
Underground Cables[1]	Continuous	Loading must be reduced below the 100 hr or 300 hr rating within 4 hours[2]	Loading must be reduced below the 100 hr or 300 hr rating within 15 minutes	requires immediate action to reduce loading below the LTE rating
Transmission Transformers	Continuous	Loading must be reduced below the Normal rating within 4 hours[2]	Loading must be reduced below the LTE rating within 15 minutes[3]	requires immediate action to reduce loading below the LTE rating

[1] Ratings for other durations may be calculated and utilized for specific conditions on a case-by-case basis. Following expiration of the 100 hr or 300 hr period, loading of the cable must be reduced below the Normal rating. Either the 100 hr or the 300 hr rating may be utilized after the transient period, but not both. If the 100 hr rating is utilized, the loading must be reduced below the Normal rating within 100 hr, and the 300 hr rating may not be used.

[2] The summer LTE rating duration is 12 hours in New England. The winter LTE rating duration in New England, and the summer and winter LTE rating duration in New York is 4 hours. The time duration does not affect the calculated value of the LTE rating. The duration difference reflects how the LTE ratings are applied by the ISO in each Area.

[3] The transformer STE rating is based on a 30 minute duration to provide additional conservatism, but is applied in operations as a 15 minute rating.

[4] The DAL rating is only calculated only in New England based on historical ISO requirements.

3.4.1 Other Equipment

Industry standards and input from task forces in New England and New York should continue to be used as sources of guidance for developing procedures for rating new types of equipment or for improving the procedures for rating the existing equipment.

3.4.2 High Voltage DC

High Voltage dc (HVdc) equipment is rated using the manufacturer's claimed capability.

3.5 System Models

Base case system models for powerflow and transient stability analysis are available from libraries maintained through a process involving the ISOs, NPCC, and the Eastern Interconnection Reliability Assessment Group (ERAG). Through this process entities supply their respective ISOs with modeling updates for their system; the ISOs combine information and develop Area updates and provide them to NPCC; NPCC combines information from all of the Areas into a regional update and provides it to ERAG; and ERAG, through the Multiregional Modeling Working Group (MMWG) combines all the regional updates into a master model which is then redistributed back down the chain for use by the industry. The modeling updates include load forecast over the ten year planning horizon (which through the course of the process are modified to recognize the diversity of the aggregate seasonal peak demand relative to the sum of the area seasonal peak demands) and equipment characteristics (e.g. impedance, line charging, normal and emergency ratings, nominal voltages, tap ratios and regulated buses for transformers, and equipment status). The modeling updates are provided in the form of solved powerflow and stability models created annually for selected years and seasons within the planning horizon. The years and seasons modeled typically are:

Near-term (one to three years out): Summer peak, winter peak. Fall peak, spring peak, and spring light load may also be looked at.

Mid-term (three to six years out): Summer peak and winter peak

Long-term (six or more years out): Summer peak.

Details on this process can be found in NPCC Document C-29, *Procedures for System Modeling: Data Requirements & Facility Ratings*, and the *MMWG Procedure Manual*.

This process is completed once per year coincident with the need to provide base cases in response to the FERC 715 filing requirement. However, updates typically are provided by or to the ISOs as information becomes available (e.g. as projects are approved or go into service). The load forecasts are seasonal peak load assumptions that include adjustments for energy efficiency. Demand response is not included in the load models. Any given base case may need to be revised to reflect local concerns (e.g. proposed system changes not included in the model, local peak loads).

When scaling load on an area basis, care must be taken to avoid scaling non-conforming load, i.e. load that does not conform to a typical load-duration curve such as industrial or generating plant station service load. When a light load case is desired in a year for which a light load base case is not available, a light load case should be developed from an available light load case for another year; this is always preferable to scaling a peak load case down to a light load level. In general, peak load cases should not be scaled below 70 percent of peak load and light load cases should not be scaled above 70 percent of peak load. When scaling load it also is necessary to be sure that generator voltage schedules and dispatch of reactive resources is appropriate for the load level modeled. In particular, generator units in the REMVEC portion of New England have different voltage schedules for heavy and light load levels.

3.6 Modeling for Powerflow Studies

The representation for powerflow studies should include models of transmission lines, transformers, generators, reactive sources, and any other equipment which can affect power flow or voltage. The representation for fixed-tap, load-tap-changing, and phase shifting transformers should include voltage or angle taps, tap ranges, and voltage or power flow control points. The representation for generators should include reactive capability ranges and voltage control points. Equipment ratings should be modeled for each of these facilities including related station equipment such as buses, circuit breakers and switches. Study specific issues that need to be addressed are discussed below.

3.6.1 Forecasted Load

The forecasted summer and winter peak active and reactive loads should be obtained annually from the Transmission Customers for a period of ten or more years starting with the highest actual seasonal peak loads within the last three years. The forecast should have sufficient detail to distribute the active and reactive coincident loads (coincident with the Customers' total peak load) across the Customers' Points of Delivery. Customer owned generation should be modeled explicitly when the size is significant compared to the load at the same delivery point, or when the size is large enough to impact system dynamic performance.

The Point of Delivery for powerflow modeling purposes may be different than the point of delivery for billing purposes. Consequently, these points need to be coordinated between National Grid and the Transmission Customer.

To address forecast uncertainty, the peak load forecast should include forecasts based on normal and extreme weather. The normal weather forecast has a 50 percent probability of being exceeded and the extreme weather forecast has a 10 percent probability of being exceeded. Due to the lead time required to construct new facilities, planning should be based conservatively on the extreme weather forecast.

3.6.2 Load Levels

To evaluate the sensitivity to daily and seasonal load cycles, many studies require modeling several load levels. The most common load levels studied are peak (100% of the extreme weather peak load forecast), intermediate (70 to 80% of the peak), and light (45 to 55% of the peak). The basis can be either the summer or winter peak forecast. In some areas, both seasons may have to be studied.

Sensitivity to the magnitude of the load assumptions must be evaluated with the assumed generation dispatch to assess the impact of different interactions on transmission circuit loadings and system voltage responses.

3.6.3 Load Balance and Harmonics

Balanced three-phase 60 Hz ac loads are assumed at each Point of Delivery unless a customer specifies otherwise, or if there is information available to confirm the load is not balanced. Balanced loads are assumed to have the following characteristics:

- The active and reactive load of any phase is within 90% to 110% of the load on both of the other phases
- The voltage unbalance between the phases measured phase-to-phase is 3% or less
- The negative phase sequence current (RMS) in any generator is less than the limits defined by the current version of ANSI C50.13

Harmonic voltage and current distortion is required to be within limits recommended by the current version of IEEE Std. 519.

If a customer load is unbalanced or exceeds harmonic limits, then special conditions not addressed in this guide may apply.

3.6.4 Load Power Factor

Load Power Factor for each delivery point is established by the active and reactive load forecast supplied by the customer in accordance with Section 3.5.1. The reactive load may be adjusted as necessary to reflect load power factor observed via the Energy Management System (EMS) or metered data. The Load Power Factor in each area in New England should be consistent with the limits set forth in Operating Procedure 17 (OP17).

3.6.5 Reactive Compensation

Reactive compensation should be modeled as it is designed to operate on the transmission system and, when provided, on the low voltage side of the supply transformers. Reactive compensation on the feeder circuits is assumed to be netted with the load. National Grid should have the data on file, as provided by the generator owners, to model the generator reactive capability as a function of generator active power output for each generator connected to the transmission system.

3.6.6 Generation Dispatch

Analysis of generation sensitivity is necessary to model the variations in dispatch that routinely occur at each load level. The intent is to bias the generation dispatch such that the transfers over select portions of the transmission system are stressed pre-contingency as much as reasonably possible. An exception is hydro generation that should account for seasonal variation in the availability of water.

A merit based generation dispatch should be used as a starting point from which to stress transfers. A merit based dispatch can be approximated based on available information such as fuel type and historical information regarding unit commitment. Interface limits can be used as a reference for stressing the transmission system. Dispatching to the interface limits may stress the transmission system in excess of transfer levels that are considered normal.

3.6.7 Facility Status

The initial conditions assume all existing facilities normally connected to the transmission system are in service and operating as designed or expected. Future facilities should be treated as discussed in Section 3.3.

3.7 Modeling For Stability Studies

3.7.1 Dynamic Models

Dynamic models are required for generators and associated equipment, HVdc terminals, SVCs, other Flexible AC Transmission Systems (FACTS), and protective relays to calculate the fast acting electrical and mechanical dynamics of the power system. Dynamic model data is maintained as required by NERC, NPCC, ISO-NE, and NYSRC.

3.7.2 Load Level and Load Models

The load levels studied in stability studies vary between New England and New York consistent with accepted practices in each Area. Stability studies within New England typically exhibit the most severe system response under light load conditions. Consequently, transient stability studies are typically performed for several unit dispatches at a system load level of 45% of peak system load. At least one unit dispatch at 100% of system peak load is also analyzed. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

Stability studies within New York typically exhibit the most severe system response under summer peak load conditions. Consequently, transient stability studies are typically performed with a system load level of 100% of summer peak system load. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch.

System loads within New England and New York are usually modeled as constant admittances for both active and reactive power. These models have been found to be appropriate for studies of rotor angle stability and are considered to provide conservative results. Other load models are utilized where appropriate such as when analyzing the underfrequency performance of an islanded portion of the system, or when analyzing voltage performance of a local portion of a system.

Loads outside NEPOOL are modeled consistent with the practices of the individual Areas and regions. Appropriate load models for other Areas and regions are available through NPCC.

3.7.3 Generation Dispatch

Generation dispatch for stability studies typically differs from the dispatch used in thermal and voltage analysis. Generation within the area of interest (generation behind a transmission interface or generation at an individual plant) is dispatched at full output within known system constraints. Remaining generation is dispatched to approximate a merit based dispatch. To minimize system inertia, generators are dispatched fully loaded to the extent possible while respecting system reserve requirements.

3.8 Modeling for Short Circuit Studies

Short Circuit studies are performed to determine the maximum fault duty at a point on the system. Transmission Planning uses this to evaluate circuit breakers fault duty withstand and to determine appropriate fault impedances for modeling unbalanced faults in transient stability studies. Other groups may use the Short Circuit information to evaluate fault duty capability for other equipment on the system. Transmission Planning also uses the fault duty to inform substation engineering of the short circuit currents (recommended and minimum) to be considered for substation design (e.g., equipment ratings, bus work & grounding system design). This requirement is noted on the Project Data Sheet (PDS).

Short Circuit studies for calculating maximum fault duty assume all generators are on line, and all transmission system facilities are in service and operating as designed. When results are used to assess whether the interrupting capability of a circuit breaker will be exceeded, the assessment must consider the switchyard configuration to determine the contribution of the total fault current the circuit breaker must interrupt. The assessment also must consider whether the circuit breaker is total-current rated or symmetrical current rated and oil circuit breakers[1] must be derated to account for autoreclosing.

The interrupting capability for symmetrical current rated circuit breakers is assessed using IEEE/ANSI in standard C37.010-1999. This method uses the system X/R ratio at the fault point as defined by the standard, the relay operating time, and the breaker contact parting time to determine a factor that is multiplied by the symmetrical current to arrive at the actual interrupting current. This current is then compared with the circuit breaker interrupting capability. If the breaker is an oil circuit breaker, the interrupting capability would be derated for reclosing duties. Special consideration may be necessary when assessing generating unit breakers.

[1] IEEE C37.010 Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis

Short Circuit studies for determining impedances for modeling unbalanced faults in stability studies typically assume all generators are on line. Switching sequences associated with the contingency may be accounted for in the calculation.

3.9 Modeling for Protection Studies

Conceptual protection system design should be performed to ensure adequate fault detection and clearing can be coordinated for the proposed transmission system configuration in accordance with the National Grid protection philosophy and where applicable, with the NPCC "Bulk Power System Protection Criteria". Preliminary relay settings should be calculated based on information obtained from powerflow, stability, and short circuit studies to ensure feasibility of the conceptual design.

Facilities subject to NPCC Bulk Power System Protection Criteria (BPS) are identified through performance analysis. As a result, analysis may be required to consider whether any recommended changes to the system configuration or protection design would impact the BPS designation of any facility. TGP29 describes this requirement in detail.

When an increase in the thermal rating of main circuit equipment is required, a review of associated protection equipment is necessary to ensure that the desired rating is achieved. The thermal rating of CT secondary equipment must be verified to be greater than the required rating. Also, it is necessary to verify that existing or proposed protective relay trip settings do not restrict loading of the protected element and other series connected elements to a level below the required circuit rating.

3.10 Other Studies

For some applications it may be necessary to include other types of studies. Examples include:

- Switching surge studies to assess voltage transients associated with switching underground cables and capacitors, or to determine minimum approach distances for live-line maintenance on overhead transmission lines.
- Harmonics studies to assess impacts of large converter loads; e.g. HVdc terminals, arc furnaces, or electric rail traction systems.
- Sub-Synchronous Resonance (SSR) studies associated with application of series capacitors or control systems associated with HVdc or Flexible AC Transmission System (FACTS) devices near large turbine-generators.

3.11 Development and Evaluation of Alternatives

If the projected performance or reliability of the system does not conform to the applicable planning criteria, then alternative solutions based on safety, performance, reliability, environmental impacts, and economics need to be developed and evaluated. The evaluation of alternatives leads to a recommendation that is summarized concisely in a report.

3.11.1 Safety

All alternatives shall be designed with consideration to public safety and the safety of operations and maintenance personnel. Characteristics of safe designs include:

- adequate equipment ratings for the conditions studied and margin for unanticipated conditions
- use of standard designs for ease of operation and maintenance
- ability to properly isolate facilities for maintenance

- adequate facilities to allow for staged construction of new facilities or foreseeable future expansion

Consideration shall be given to address any other safety issues that are identified that are unique to a specific project or site.

3.11.2 Performance

The system performance with the proposed alternatives should meet or exceed all applicable design criteria.

3.11.3 Reliability

This guide assesses deterministic reliability by defining the topology, load, and generation conditions that the transmission system must be capable of withstanding safely. This deterministic approach is consistent with NERC, NPCC, ISO-NE, and NYSRC practice. Defined outage conditions that the system must be designed to withstand are listed in Table 4.1. The transmission system is designed to meet these deterministic criteria to promote the reliability and efficiency of electric service on the bulk power system, and also with the intent of providing an acceptable level of reliability to the customers.

Application of this guide ensures that all customers receive an acceptable level of reliability, although the level of reliability provided through this approach will vary. All customers or groups of customers will not necessarily receive uniform reliability due to inherent factors such as differences in customer load level, load shape, proximity to generation, interconnection voltage, accessibility of transmission resources, customer service requirements, and class and vintage of equipment.

3.11.4 Environmental

An assessment should be made for each alternative of the human and natural environmental impacts. Assessment of the impacts is of particular importance whenever expansion of substation fence lines or transmission rights-of-way are proposed. However, environmental impacts also should be evaluated for work within existing substations and on existing transmission structures. Impacts during construction should be evaluated in addition to the impact of the constructed facilities. Evaluation of environmental impacts will be performed consistent with all applicable National Grid policies.

3.11.5 Economics

Initial and future investment cost estimates should be prepared for each alternative. The initial capital investment can often be used as a simple form of economic evaluation. This level of analysis is frequently adequate when comparing the costs of alternatives for which all expenditures are made at or near the same time. Additional economic analysis is required to compare the total cost of each alternative when evaluating more complex capital requirements, or for projects that are justified based on economics such as congestion relief. These analyses should include the annual charges on investments, losses, and all other expenses related to each alternative.

A cash flow model is used to assess the impact of each alternative on the National Grid business plan. A cumulative present worth of revenue requirements model is used to assess the impact of each alternative on the customer. Evaluation based on one or both models may be required depending on the project.

If the justification of a proposed investment is to reduce or eliminate annual expenses, the economic analysis should include evaluation of the length of time required to recover the investment. Recovery of the investment within 5 years is typically used as a benchmark, although recovery within a shorter or longer period may be appropriate.

3.11.6 Technical Preference

Technical preference should be considered when evaluating alternatives. Technical preference refers to concerns such as standard versus non-standard design or to an effort to develop a future standard. It may also refer to concerns such as age and condition of facilities, availability of spare parts, ease of operations and maintenance, ability to accommodate future expansion, ability to implement, or reduction of risk.

3.11.7 Sizing of Equipment

All equipment should be sized based on economics, operating requirements, standard sizes used by the company, and engineering judgment. Economic analysis should account for indirect costs in addition to the cost to purchase and install the equipment. Engineering judgment should include recognition of realistic future constraints that may be avoided with minor incremental expense. As a guide, unless the equipment is part of a staged expansion, the capability of any new equipment or facilities should be sufficient to operate without constraining the system and without major modifications for at least 10 years. As a rough guide, if load growth is assumed to be 1% to 2%, then the minimum reserve margin should be at least 20% above the maximum expected demand on the equipment at the time of installation. However, margins can be less for a staged expansion.

3.12 Recommendation

A recommended action should result from every study. The recommendation includes resolution of any potential violation of the design criteria. The recommended action should be based on composite consideration of factors such as safety, the forecasted performance and reliability, environmental impacts, economics, technical preference, schedule, availability of land and materials, acceptable facility designs, and complexity and lead time to license and permit.

3.13 Reporting Study Results

A transmission system planning study should culminate in a concise report describing the assumptions, procedures, problems, alternatives, economic comparison, conclusions, and recommendations resulting from the study.

4.0 Design Criteria

4.1 Objective of the Design Criteria

The objective of the Design Criteria is to define the design contingencies and measures used to assess the adequacy of the transmission system performance.

4.2 Design Contingencies

The Design Contingencies used to assess the performance of the transmission system are defined in Table 4.1. In association with the design contingencies, this table also includes information on allowable facility loading. Control actions may be available to mitigate some contingencies listed in Table 4.1.

The reliability of local areas of the transmission system may not be critical to the operation of the interconnected NEPOOL system and the New York State Power System. Where this is the case, the system performance requirements for the local area under National Grid design contingencies may be less stringent than what is required by NERC Reliability Standards, NPCC Criteria, ISO-NE Reliability Standards, or NYSRC Reliability Rules.

4.2.1 Fault Type

As specified in Table 4.1, some contingencies are modeled without a fault; others are modeled with a three phase or a single phase to ground fault. All faults are considered permanent with due regard for reclosing facilities and before making any manual system adjustments.

4.2.2 Fault Clearing

Design criteria contingencies involving ac system faults on bulk power system facilities are simulated to ensure that stability is maintained when either of the two independent protection groups that performs the specified protective function operates to initiate fault clearing. In practice, design criteria contingencies are simulated based on the assumption that a single protection system failure has rendered the faster of the two independent protection groups inoperable.

Design criteria contingencies involving ac system faults on facilities that are not part of the bulk power system are simulated based on correct operation of the protection system on the faulted element. Facilities that are not part of the bulk power system must be reviewed periodically to determine whether changes to the power system have caused facilities to become part of the bulk power system. National Grid utilizes for this purpose a methodology based on applying a three-phase fault, uncleared locally, and modeling delayed clearing of remote terminals of any elements that must open to interrupt the fault.

4.2.3 Allowable Facility Loading

The normal rating of a facility defines the maximum allowable loading at which the equipment can operate continuously. The LTE and STE ratings of equipment may allow an elevation in operating temperatures over a specific period provided the emergency loading is reduced back to, or below, a specific loading in a specific period of time (for specific times, see Section 3.4).

The system should be designed to avoid loading equipment above the normal rating prior to a contingency and to avoid loading equipment above the LTE rating following a design contingency (see Table 4.1 contingencies a through i). Under limited circumstances, however, it is acceptable to design the system such that equipment may be loaded above the LTE rating, but lower than the STE rating. Loading above the LTE rating up to the STE rating is permissible for contingencies b, c, e, f, g, h, and i, for momentary conditions, provided automatic actions are in place to reduce the loading of the equipment below the LTE rating within 15 minutes, and it does not cause any other facility to be loaded above its LTE rating. Such exceptions to the criteria will be well documented and require acceptance by National Grid Network Operations.

The STE rating is dependent on the level of loading prior to applying a contingency. The published STE rating is valid when the pre-contingency loading is within the normal rating. When the pre-contingency loading exceeds the normal rating, the STE rating must be reduced to prevent equipment from exceeding its allowable emergency temperature.

In New England an additional rating, the Drastic Action Limit (DAL), is calculated for use in real-time operations. The DAL is an absolute operating limit, based on the maximum loading to which a piece of equipment can be subjected over a five-minute period without sustaining damage. Although the DAL is computed based on a five minute load duration, if equipment loadings reach a level between the STE and DAL limits, then immediate action is required to reduce loading to below LTE. The DAL is not used in planning studies or for normal operating situations. In some cases when the STE rating may be exceeded, it may be necessary to provide redundant controls to minimize the risk associated with failure of the automated actions to operate as intended.

4.2.4 Reliability of Service to Load

The transmission system is designed to allow the loss of any single element without a resulting loss of load, except in cases where a customer is served by a single supply. Where an alternate supply exists, interruption of load is acceptable for the time required to transfer the load to the alternate supply.

Loss of load is acceptable for contingencies that involve loss of multiple elements such as simultaneous outage of multiple circuits on a common structure, or a circuit breaker failure resulting in loss of multiple elements. For these contingencies, measures should be evaluated to mitigate the frequency and/or the impact of such contingencies when the amount of load interrupted exceeds 100 MW. Such measures may include differential insulation of transmission circuits on a common structure, or automatic switching to restore unfaulted elements. Where such measures are already implemented, they should be assumed to operate as intended, unless a failure to operate as intended would result in a significant adverse impact outside the local area.

A higher probability of loss of customer load is acceptable during an extended generator or transformer outage, maintenance, or construction of new facilities. Widespread outages resulting from contingencies more severe than those defined by the Design Contingencies may result in loss of customer load in excess of 100 MW and/or service interruptions of more than 3 days.

4.2.5 Load Shedding

NPCC requires that each member have underfrequency load shedding capability to prevent widespread system collapse. As a result, load shedding for regional needs is acceptable in whatever quantities are required by the region. In some cases higher quantities of load shedding may be required by the Area or the local System Operator.

Manual or automatic shedding of any load connected to the National Grid transmission system in response to a design contingency listed in Table 4.1 may be employed to maintain system security when adequate facilities are not available to supply load. However, shedding of load is not acceptable as a long term solution to design criteria violations, and recommendations will be made to construct adequate facilities to maintain system security without shedding load.

4.2.6 Expected Restoration Time

The transmission restoration time for the design contingencies encountered most frequently is typically expected to be within 24 hours. Restoration times are typically not more than 24 hours for equipment including overhead transmission lines, air insulated bus sections, capacitor banks, circuit breakers not installed in a gas insulated substation, and transformers that are spared by a mobile substation. For some contingencies however, restoration time may be significantly longer. Restoration times are typically longer than 24 hours for generators, gas insulated substations, underground cables, and large power transformers. When the expected restoration for a particular contingency is expected to be greater than 24 hours, analysis should be performed to determine the potential impacts if a second design contingency were to occur prior to restoration of the failed equipment.

4.2.7 Generation Rejection or Ramp Down

Generation rejection or ramp down refers to tripping or running back the output of a generating unit in response to a disturbance on the transmission system. As a general practice, generation rejection or ramp down should not be included in the design of the transmission system. However, generation rejection or ramp down may be considered if the following conditions apply:

- acceptable system performance (voltage, current, and frequency) is maintained following such action
- the interconnection agreement with the generator permits such action
- the expected occurrence is infrequent (the failure of a single element is not typically considered infrequent)
- the exposure to the conditions is unlikely or temporary (temporary implies that system modifications are planned in the near future to eliminate the exposure or the system is operating in an abnormal configuration).

Generation rejection or ramp down may be initiated manually or through automatic actions depending on the anticipated level and duration of the affected facility loading. Plans involving generation rejection or ramp down require review and approval by National Grid Network Operations, and may require approval of the System Operator.

4.2.8 Exceptions

These Design Criteria do not apply if a customer receives service from National Grid and also has a connection to any other transmission provider regardless of whether the connection is open or closed. In this case, National Grid has the flexibility to evaluate the situation and provide interconnection facilities as deemed appropriate and economic for the service requested.

National Grid is not required to provide service with greater deterministic reliability than the customers provide for themselves. As an example, if a customer has a single transformer, National Grid does not have to provide redundant transmission supplies.

4.3 Voltage Response

Acceptable voltage response is defined in terms of maximum and minimum voltage in per unit (p.u.) for each transmission voltage class (Table 4.2), and in terms of percent voltage change from pre-contingency to post-contingency (Table 4.3). The values in these tables allow for automatic actions that take less than one minute to operate and which are designed to provide post-contingency voltage support. The voltage response also must be evaluated on the basis of voltage transients.

4.4 Stability

4.4.1 System Stability

Stability of the transmission system shall be maintained during and following the most severe of the Design Contingencies in Table 4.1, with due regard to reclosing. Stability shall also be maintained if the outaged element as described in Table 4.1, is re-energized by autoreclosing before any manual system adjustment.

In evaluating the system response it is insufficient to merely determine whether a stable or unstable response is exhibited. There are some system responses which may be considered unacceptable even though the bulk power system remains stable. Each of the following responses is considered an unacceptable response to a design contingency:

- Transiently unstable response resulting in wide spread system collapse.
- Transiently stable response with undamped power system oscillations.

4.4.2 Generator Unit Stability

With all transmission facilities in service, generator unit stability shall be maintained on those facilities that remain connected to the system following fault clearing, for

a. A permanent single-line-to-ground fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time with due regard to reclosing.

b. A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, cleared in normal time with due regard to reclosing.

Isolated generator instability may be acceptable. However, generator instability will not be acceptable if it results in adverse system impact or if it unacceptably impacts any other entity in the system.

4.5 Generator Low Voltage Ride Through

All generators should be capable of riding through low voltage transient conditions in which Generator Unit Stability is maintained. If there are concerns, it may be necessary to obtain information from generator owners on generator protection settings to confirm that a generator is actually capable of riding through low voltage transient conditions. (Draft NERC Standard PRC-024-1 is to be used as a reference.)

Table 4.1: Design Contingencies

Ref.	CONTINGENCY (Loss or failure of:)	Allowable Facility Loading
a	A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section	LTE
b	Simultaneous permanent single-line-to-ground faults on different phases of two adjacent transmission circuits on a multiple circuit tower (> 5 towers)[2]	LTE[1]
c	A permanent single-line-to-ground fault on any transmission circuit, transformer, or bus section, with a breaker failure	LTE[1]
d	Loss of any element without a fault (including inadvertent opening of a switching device	LTE
e	A permanent single-phase-to-ground fault on a circuit breaker with normal clearing	LTE[1]
f	Simultaneous permanent loss of both poles of a bipolar HVdc facility without an ac system fault	LTE[1]
g	Failure of a circuit beaker to operate when initiated by an SPS following: loss of any element without a fault, or a permanent single-line-to-ground fault on a transmission circuit, transformer, or bus section	LTE[1]
h	Loss of a system common to multiple transmission elements (e.g., cable cooling)	LTE[1]
i	Permanent single-line-to-ground faults on two cables in a common duct or trench	LTE[1]

Notes:

[1] Loading above LTE, but below STE, is acceptable for momentary conditions provided automatic actions are in place to reduce the loading of equipment below the LTE rating within 15 minutes.

[2] If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, subject to approval in accordance with Regional (NPCC) and Area (NYSRC or ISO-NE) exemption criteria, where applicable.

Table 4.2: Voltage Range

CONDITION	345 & 230 kV		115 kV[1] & Below	
	Low Limit (p.u.)	**High Limit (p.u.)**	**Low Limit (p.u.)**	**High Limit (p.u.)**
Normal Operating	0.98	1.05	0.95	1.05
Post Contingency & Automatic Actions	0.95	1.05	0.90	1.05

[1] Buses that are part of the bulk power system, and other buses deemed critical by Network Operations shall meet requirements for 345 kV and 230 kV buses.

Table 4.3: Maximum Percent Voltage Variation at Delivery Points

CONDITION	345 & 230 kV (%)	115 kV[1] & Below (%)
Post Contingency & Automatic Actions	5.0	10.0
Switching of Reactive Sources or Motor Starts (All elements in service)	2.0 *	2.5 *
Switching of Reactive Sources or Motor Starts (One element out of service)	4.0 *	5.0 *

[1] Buses that are part of the bulk power system, and other buses deemed critical by Network Operations shall meet requirements for 345 kV and 230 kV buses.

* These limits are maximums which do not include frequency of operation. Actual limits will be considered on a case-by-case basis and will include consideration of frequency of operation and impact on customer service in the area.

Notes to Tables 4.2 and 4.3:

a. Voltages apply to facilities which are still in service post contingency.
b. Site specific operating restrictions may override these ranges.
c. These limits do not apply to automatic voltage regulation settings which may be more stringent.
d. These limits only apply to National Grid facilities.

5.0 Interconnection Design Requirements

5.1 Objective of the Interconnection Design Requirements

The objective of the interconnection design requirements is to provide guidance on the minimum acceptable configurations to be applied when a new generator or transmission line is to be interconnected with the National Grid transmission system. The goal is to assure that reliability and operability are not degraded as a consequence of the new interconnection. National Grid will determine the configuration that appropriately addresses safety, reliability, operability, maintainability, and expandability objectives, consistent with this Transmission Planning Guide for each new or revised interconnection.

5.2 Design Criteria

5.2.1 Safety

Substation arrangements shall be designed with safety as a primary consideration. Standard designs shall be utilized for ease of operation and maintenance and to promote standardization of switching procedures. Substation arrangements shall also provide means to properly isolate equipment for maintenance and allow appropriate working clearances for installed equipment as well as for staged construction of future facilities. Consideration shall be given to address any other safety issues that are identified that are unique to a specific project or site.

5.2.2 Planning and Operating Criteria

Substation arrangements shall be designed such that all applicable Planning and Operating Criteria are met. These requirements may require ensuring that certain system elements do not share common circuit breakers or bus sections so as to avoid loss of both elements following a breaker fault or failure; either by relocating one or both elements to different switch positions or bus sections or by providing two circuit breakers in series. These requirements may also require that existing substation arrangements be reconfigured, e.g. from a straight bus or ring bus to a breaker-and-a-half configuration.

5.2.3 System Protection

Substation arrangements shall provide for design of dependable and secure protection systems. Designs that create multi-terminal lines shall not be allowed except in cases where Protection Engineering verifies that adequate coordination and relay sensitivity can be maintained when infeed or outfeed fault current is present.

To ensure reliable fault clearing, it generally is desirable that no more than two circuit breakers be required to be tripped at each terminal to clear a fault on a line or cable circuit. For transformers located within the substation perimeter, the incidence of faults is sufficiently rare that this requirement may be relaxed to permit transformers to be connected directly to the buses in breaker-and-a-half or breaker-and-a-third arrangements.

5.2.4 Reliability

Factors affecting transmission reliability shall be considered in interconnection designs. These factors include, but are not limited to:

- additional exposure to transmission outages resulting from additional transmission line taps, with consideration to length of the proposed tap,
- the number of other taps already existing on the subject line. In general, new taps will be avoided if three or more taps already exist,
- the number and type of customers already existing on the subject line and potential impacts to these customers resulting from a proposed interconnection,
- the existing performance of the subject line and how the proposed interconnection will affect that performance, and
- the impact on the complexity of switching requirements, and the time and personnel required to perform switching operations.

Periodic transmission assessments shall consider whether system modifications are necessary to improve reliability in locations where greater than three taps exist on a single transmission line.

5.2.5 Operability

Substation switching shall be configured to prevent the loss of generation for normal line operations following fault clearing. Generators shall not be connected directly to a transmission line through a single circuit breaker position except as noted in Section 5.4.2.

5.2.6 Maintainability

Substations shall be configured to permit circuit breaker maintenance to be performed without taking lines or generators out of service, recognizing that a subsequent fault on an element connected to the substation might result in the isolation of more than the faulted element. At existing substations with straight bus configurations, consideration will be given to modifying terminations in cases where an outage impacts the ability to operate the system reliably.

5.2.7 Future Expansion

Substation designs shall be based on the expected ultimate layout based on future existing system needs and physical constraints associated with the substation plot.

5.3 Standard Bus Configurations

Given the development of the transmission system over time and through mergers and acquisitions of numerous companies, several different substation arrangements exist within the National Grid system. Future substation designs are standardized on breaker-and-a-half, breaker-and-a-third, and ring bus configurations, depending on the number of elements to be terminated at the station. Other substation configurations may be retained at existing substations, but are evaluated in periodic transmission assessments to consider whether continued use of such configurations is consistent with the reliable operation of the transmission system.

Determination of the appropriate substation design is based on the total number of elements to be terminated in the ultimate layout, and how many major transmission elements will be terminated. Guidance is also available in ISO-NE Planning Policy 9 (PP9 Major Substation Bus

Arrangement Application Guidelines). Major transmission elements include networked transmission lines 115 kV and above and power transformers with at least one terminal connected at 230 kV or 345 kV.

5.3.1 Breaker-and-a-Half

A breaker-and-a-half configuration is the preferred substation arrangement for new substations with an ultimate layout expected to terminate greater than four major transmission elements or greater than six total elements. If the entire ultimate layout is not constructed initially, the substation may be configured initially in a ring bus configuration. Cases will exist where a breaker-and-a-half configuration is required with fewer elements terminated in order to meet the criteria stated above.

Major transmission elements are terminated in a bay position between two circuit breakers in a breaker-and-a-half configuration. Other elements such as capacitor banks, shunt reactors, and radial 115 kV transmission lines may be terminated on the bus through a single circuit breaker. Transformers with no terminal voltage greater than 115 kV may be terminated directly on a bus. It may be permissible to terminate 345-115 kV or 230-115 kV transformers directly on a 115 kV bus if there is no reasonable expectation that more than two such transformers will be installed. Such a decision requires careful consideration however, given the difficulty of re-terminating transformers to avoid tripping two transformers for a breaker fault or failure in the event that a third transformer is installed at a later time.

5.3.2 Breaker-and-a-Third

A breaker-and-a-third configuration is an acceptable alternate to a breaker-and-a-half configuration in cases where a breaker-and-a-half arrangement is not feasible due to physical or environmental constraints. Considerations for terminating elements on a bus are the same as for breaker-and-a-half, except that 345-115 kV or 230-115 kV transformers may be terminated directly on a 115 kV bus since additional transformers may be terminated in a bay without a common breaker between two transformers.

5.3.3 Ring Bus

A ring bus may be utilized for new substations where four or fewer major elements will be terminated or six or fewer total elements will be terminated. A ring bus also may be utilized as an interim configuration during staged construction of a substation.

5.3.4 Straight Bus

Many older substations on the system have a straight bus configuration, with each element terminating on the bus through a single breaker. Variations exist in which the bus is segmented by one or more bus-tie breakers, provisions are provided for a transfer bus, or the ability exists to transfer some or all elements from the main bus to an emergency bus. Periodic transmission assessments shall consider whether continued use of existing straight bus configurations is consistent with maintaining reliable operation of the transmission system.

New bulk power system substations shall not utilize a straight bus design. Straight bus designs may be utilized at non-bulk power system substations subject to the following conditions:

- A transfer bus is provided to facilitate circuit breaker maintenance.
- The transfer breaker protection system is capable of being coordinated to provide adequate protection for any element connected to the bus.

- Justification is provided to support deviating from the standard breaker-and-a-half, breaker-and-a-third, or ring bus configuration.
- All requirements of Section 5.2 are met.

5.4 Substation Design Considerations

5.4.1 NPCC Bulk Power System Design Requirements

When an element has been identified as part of the NPCC bulk power system, the protection system for that element must be designed to meet the NPCC Directory #4 *Bulk Power System Protection Criteria*. These criteria require redundancy and separation of protection system components and have a significant impact on physical space requirements as well as project scope, schedule, and cost. These impacts typically are greatest when modifications are required at existing substations. Given that these impacts can be significant, it is appropriate to consider designing and in some cases pre-building facilities to meet these requirements to avoid more costly retrofitting at a later time. The following guidance is provided for cases where facilities have been identified as part of the NPCC bulk power system[2], have the potential to become bulk power system facilities, or are unlikely to become bulk power system facilities.

5.4.1.1 NPCC bulk power system facilities: These facilities have been identified as part of the bulk power system through application of the NPCC A-10 *Criteria for Classification of Bulk Power System* Elements.

These facilities always are designed and constructed to meet NPCC Criteria.

5.4.1.2 Potential NPCC bulk power system facilities: These facilities have not been identified as part of the bulk power system through application of the NPCC A-10 *Criteria for Classification of Bulk Power System Elements*, but have been identified as potential bulk power system facilities through the results of testing (e.g. marginally acceptable results), proximity to existing bulk power system facilities, or are reasonably expected to become part of the bulk power system due to proposed transmission reinforcements within the 10-year planning horizon. The extent to which facilities will be designed and constructed to meet NPCC Criteria must consider scope, schedule, and cost of future modifications of the facilities compared to the incremental scope, schedule, and cost of designing or constructing to meet NPCC Criteria as part of the project.

New substations are expected to be designed to meet NPCC Criteria, but are not expected to be constructed to meet NPCC Criteria except where the incremental cost is minimal, e.g. circuit breakers purchased with two current transformers per bushing and two trip coils. Locations are identified for future batteries, cable conduits, etc. and incorporated into drawings.

Modifications at existing substations must consider the extent of work related to the project compared to future work that may be required to meet NPCC Criteria.

If major modifications are being made at a substation and deferring design to meet NPCC Criteria would significantly increase future scope, schedule, and cost; then incorporating the design changes in the project to meet NPCC Criteria must be considered.

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[2] The List of Bulk Power System Elements is maintained through testing included as part of NERC Compliance Studies, System Impact Studies, and local area transmission studies. Results of these studies are provided to the appropriate ISO to initiate the process for updating the list as provided in Section 5.0 of TGP29 “Maintenance of the National Grid List of Bulk Power System Elements”. TGP29 provides detailed information on how National Grid applies the NPCC A-10 Criteria in these studies.

If minor modifications are being made at a substation, then the facilities are designed to meet NPCC Criteria only when there will not be a significant impact on the scope, schedule, or cost of the project.

5.4.1.3 System facilities Unlikely to be Classified as NPCC Bulk Power: These facilities have not been identified as bulk through application of the NPCC A-10 *Criteria for Classification of Bulk Power System Elements*, and are unlikely to become part of the bulk power system within the 10-year planning horizon.

These facilities are not designed or constructed to meet NPCC Criteria.

5.4.2 Independent Pole Tripping Circuit Breakers

Circuit breakers with independent pole tripping (IPT) capability may be installed to mitigate the impact of an extreme contingency three-phase fault accompanied by a breaker failure. The independent operating mechanisms and control circuitry for each pole of the circuit breaker result in a high probability that a breaker failure will result in a failure to interrupt the fault current in only one breaker pole. In simulations of these extreme contingencies the fault is downgraded from three-phase to single-line-to-ground after failure of a circuit breaker with IPT capability and clearing of other sources contributing to the fault.

The National Grid standard design specification for 345 kV circuit breakers requires IPT capability for all applications. At transmission voltages 230 kV and below, circuit breakers with IPT capability are installed based on a case-by-case review considering the potential impact to be mitigated and the incremental cost of the circuit breaker application. The incremental cost consists of two components. The first component is the incremental equipment cost for purchasing the circuit breaker. The second component is associated with additional auxiliary relays and increased control wiring requirements.

Circuit breakers with IPT capability are applied at transmission voltages 230 kV and below when transient stability simulations of three-phase faults accompanied by a breaker failure indicate a basic system weakness that jeopardizes the integrity of the overall bulk power system. In these cases adding or replacing circuit breakers with IPT capability is justified to comply with NPCC Directory #1, *Design and Operation of the Bulk Power System*.

When 230 kV or 115 kV circuit breakers are added or replaced at bulk power system substations, IPT capability should be considered when there will not be a significant impact on the scope, schedule, or cost of the project. In these cases the incremental cost is justified to avoid the potential for significant cost to replace the circuit breakers later if system changes result in a basic system weakness that jeopardizes the integrity of the overall bulk power system.

5.4.3 Placement of Surge Arrestors

Surge arrestors are sometimes applied on substation buses at air-insulated substations. Surge arrestors also are applied on equipment terminals when the element connected to the bus is an underground cable or transformer.

Surge arrestors also may be applied on line terminals at air-insulated substations to limit transient overvoltage at 230 kV and 345 kV. The need for line arrestors is determined on case-by-case basis either instead of or in addition to pre-insertion closing resistors in the circuit breakers at the remote line terminal. In these cases a line arrestor may be necessary to control switching surges when the line is energized from the remote terminal when the local terminal is open (in which case the bus arrestor cannot control the switching surge).

Surge arresters are applied on equipment terminals for all elements connected to a gas-insulated substation via SF6 to air bushings.

5.5 Issues Specific to Generator Interconnections

5.5.1 Interconnection Voltage

It is desirable to connect generators at the lowest voltage class available in the area for which an interconnection is feasible. In general, small generators no larger than 20 MW will be interconnected to the transmission system only when there is no acceptable lower voltage alternative in the area and it is not feasible to develop a lower voltage alternative.

5.5.2 Interconnection Facilities

The minimum interconnection required for all generators is a three-breaker ring bus. Additional circuit breakers and alternate substation configurations may be required when interconnecting multiple generating units. Generators shall not be connected directly to a transmission line through a single circuit breaker position unless an exception is granted as noted below.

Exceptions to the Generators Interconnection Requirements

Exceptions may be granted for either of the following two conditions: (1) generators connected to radial transmission lines, and (2) small generators no larger than 20 MW. Exceptions shall be evaluated on a case-by-case basis and shall be granted only when the following conditions are met:

- Protection Engineering verifies that the transmission line and interconnection facilities can be protected adequately, while ensuring that transmission system protective relay coordination and relay sensitivity can be maintained.
- Transmission Planning verifies that transmission reliability is not adversely impacted by assessing the Design Criteria listed above in Section 5.2 above pertaining to safety, planning and operating criteria, reliability, and maintainability.
- Provisions acceptable to National Grid are made to accommodate future expansion of the interconnection to at least a three-breaker ring bus.

5.5.3 Status of Interconnection Design

The design for any generator interconnection is valid only for the generating capacity and unit characteristics specified by the developer at the time of the request. Any modifications to generating capacity and unit characteristics require a separate system impact study and may result in additional interconnection requirements.

Modifications to the interconnection design may be required as a result of future modifications to the transmission system. National Grid will notify the generation owner when such modifications are required.

5.5.4 Islanding of Load and Generation

System operation with generation and customer load islanded from the transmission system is undesirable due to frequency and voltage fluctuations that likely will occur as a result of an imbalance between load and generation. When the potential exists for islanding load and generation for N-1 or N-1-1 contingencies, the interconnection protection must be designed to detect when the generation is islanded with load to ensure tripping of the generator. The protection requirements are relatively straight-forward when the maximum output of the generation is less than the minimum connected load. When it is possible for the load and generation to be balanced detection is more difficult and direct transfer tripping of the generator may be required.

6.0 Glossary of Terms

Bulk Power System
The interconnected electrical system comprising generation and transmission facilities on which faults or disturbances can have a significant impact outside the local area.

Contingency
An event, usually involving the loss of one or more elements, which affects the power system at least momentarily.

Element
Any electric device with terminals which may be connected to other electric devices, such as a generator, transformer, transmission circuit, circuit breaker, an HVdc pole, braking resistor, a series or shunt compensating device or bus section. A live-tank circuit breaker is understood to include its associated current transformers and the bus section between the breaker bushing and its free standing current transformer(s).

Fault Clearing - Delayed
Fault Clearance consistent with correct operation of a breaker failure protection group and its associated breakers or of a backup protection group with an intentional time delay.

Fault Clearing - Normal
Fault Clearance consistent with correct operation of the protection system and with correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that protection system.
Note: Zone 2 clearing of line-end faults on lines without pilot protection is normal clearing, not delayed clearing, even though a time delay is required for coordination purposes.

High Voltage dc (HVdc) System, Bipolar
An HVdc system with two poles of opposite polarity and negligible ground current.

Interface
A group of transmission lines connecting two areas of the transmission system.

Load Cycle
The normal pattern of demand over a specified time period (typically 24 hours) associated with a device or circuit.

Load Level
A scale factor signifying the total load relative to peak load or the absolute magnitude of load for the year referenced.

Loss of Customer Load (or Loss of Load)
Loss of service to one or more customers for longer than the time required for automatic switching.

Point(s) of Delivery
The point(s) at which the Company delivers energy to the Transmission Customer.

Special Protection Systems

A protection system designed to detect abnormal system conditions and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages, or power flows. Automatic underfrequency load shedding and conventionally switched locally controlled shunt devices are not considered to be SPSs.

Supply Transformer

Transformers that only supply distribution load to a single customer.

Transfer

The amount of electrical power that flows across a transmission circuit or interface.

Transmission Customer

Any entity that has an agreement to receive wholesale service from the National Grid transmission system.

Transmission Transformer

Any transformer with two or more transmission voltage level windings or a transformer serving two or more different customers.